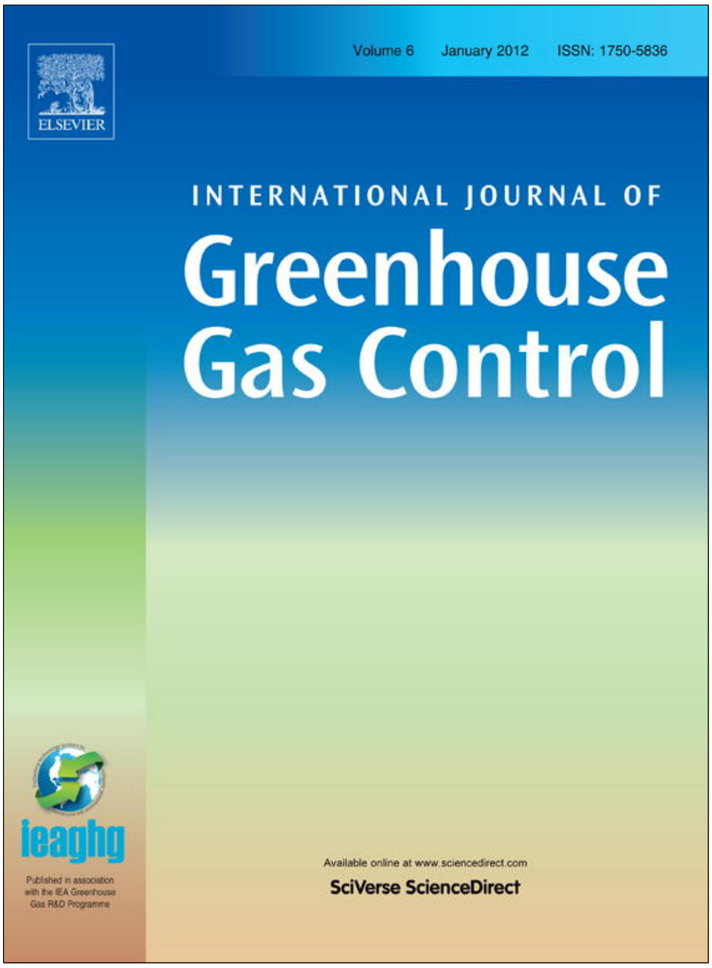
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Impact-driven pressure management via targeted brine extraction—Conceptual studies of CO_2 storage in saline formations

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ABSTRACT

Large-scale pressure buildup in response to carbon dioxide (CO_2) injection in the subsurface may limit the dynamic storage capacity of suitable formations, because elevated pressure can impact caprock integrity, induce reactivation of critically stressed faults, drive CO_2 and/or brine through conductive features into shallow groundwater resources, or may affect existing subsurface activities such as oil and gas production. It has been suggested that pressure management involving the extraction of native fluids from storage formations can be used to control subsurface pressure increases caused by CO_2 injection and storage, thereby limiting the possibility of unwanted effects. In this study, we introduce the concept of "impact-driven pressure management (IDPM)," which involves optimization of fluid extraction to meet local (not global) performance criteria (i.e., the goal is to limit pressure increases primarily where environmental impact is a concern). We evaluate the feasibility of IDPM for a hypothetical CO_2 storage operation in an idealized multi-formation system containing a critically stressed fault zone. Using a newly developed analytical solution, we assess alternative fluid extraction schemes and test whether a predefined performance criterion can be achieved, in this case the maximum allowable pressure near the fault zone. Alternative strategies for well placement are evaluated, comparing near-injection arrays of extraction wells with near-impact arrays. Extraction options include active extraction wells and (passive) pressure relief wells, as well as combinations of both, with and without reinjection into the subsurface. Our results suggest that strategic well placement and optimization of extraction may allow for a significant reduction in the brine extraction volumes. Additional work is required in the future to test the general concept of IDPM for more complex and realistic CO_2 storage scenarios.

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1. Introduction

For geologic carbon sequestration (GCS) to have a positive effect on reducing or at least stabilizing atmospheric carbon levels, the anticipated volume of CO_2 that would need to be injected in the subsurface is very large (e.g., Zhou and Birkholzer, 2011). One single coal-fired power plant alone may emit as much as 5–10 million tons of CO_2 per year. Unless storage is conducted in depleted oil or gas reservoirs, where fluids have been previously extracted as a result of production, the pore space in suitable storage formations is already filled with saline water. The CO_2 volume injected into saline formations then needs to be accommodated by expansion of reservoir pore space and compression of fluid in response to pressure buildup and, if reservoir boundaries are open, by pressure-driven migration of native brines into neighboring formations. Large and lasting pressure perturbation in the subsurface is an expected feature of GCS operations (e.g., Nicot, 2008; Birkholzer et al., 2009; Birkholzer and Zhou, 2009), and careful monitoring and management of pressure increases is generally considered of great importance to the safety of geologic carbon sequestration projects.

Potential risks related to elevated formation pressure include geomechanical effects such as caprock fracturing and/or fault reactivation (e.g., Rutqvist et al., 2007, 2008), and environmental impacts caused by pressure-driven leakage of CO_2 and/or brine through conductive pathways such as improperly plugged abandoned wells (e.g., Carroll et al., 2009; Zheng et al., 2009; Apps et al., 2010). Large-scale pressurization can also be an issue for activities involving exploitation of subsurface resources in the area, such as oil and gas or geothermal energy, or may affect neighboring CO_2 storage sites that reside in the same formation. Regarding the latter, the potential for pressure interference between GCS operations was illustrated in a regional-scale simulation for the Illinois Basin in the USA (Birkholzer and Zhou, 2009; Zhou et al., 2010). Such interference not only leads to cumulative effects of pressurization, but also has regulatory implications, since permitting needs to be conducted based on a multi-site evaluation (Birkholzer and Zhou, 2009), which can be complicated. The recent EU directive on geological storage of CO_2 (EU Directive, 2009) requires that GCS operations need to be managed in such a way that they will not impact other storage sites. It follows that there are restrictions to pressure increases

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(in spatial extent, magnitude, and duration), which can be an important factor limiting the amount of CO_2 that can be injected and stored.

One possible approach for management of formation pressure is to extract native fluids residing in the CO_2 storage reservoir so that additional pore space is provided (e.g., Court et al., 2011; Bergmo et al., 2011). While pressure management via brine extraction should not be considered a mandatory component for large-scale CO_2 sequestration projects, it can provide many benefits, such as increased storage capacity, reduced failure risk, simplified permitting, smaller area of review for site characterization, smaller area for monitoring, and, possibly, manipulation of the CO_2 plume. A large-scale CO_2 geological storage project is currently planned in Gorgon, Australia, where CO_2 injection will start in 2014 at a rate of 3.4 million tons per year. Pressure management will be conducted with four brine extraction wells designed in a line pattern, about 4 or 5 km away from the injection wells.

Buscheck et al. (2011a,b) introduced "Active CO_2 Reservoir Management (ACRM)", a brine-extraction concept that utilizes complex extraction schemes to control pressure buildup and manipulate CO_2 plume behavior. The authors assumed an extraction ratio of one, meaning that the volume of extracted brine is equal to the injected CO_2 volume. (The extraction ratio is defined as the extracted volume of brine divided by the injected CO_2 volume.) It was demonstrated with numerical simulations that extraction of brine from the lower portion of the storage formation, from locations progressively further from the center of injection, can counteract the buoyancy force that drives CO_2 to the top of the storage formation, thereby allowing for higher storage efficiency and improved injectivity. Brine extraction may also create economic value via beneficial use of treated brine (e.g., Bourcier et al., 2011; Maulbetsch and DiFillipo, 2010) or may reduce other costs for CO_2 storage, such as those related to compression, liability insurance, site characterization, or monitoring (Buscheck et al., 2011b).

On the other hand, brine extraction requires pumping, transportation, possibly treatment, and disposal of substantial volumes of extracted brackish or saline water, all of which can be technically challenging and expensive. Harto and Veil (2011) and Harto et al. (2011) evaluated the cost of extracted water management based on analogs from water production in oil and gas operations. While their estimates vary widely depending on location (e.g., transportation distance, discharge options), brine characteristics (e.g., TDS, contaminants), and selected water management options (e.g., disposal of brines, beneficial use such as desalination for drinking water production), the authors conclude that the cost of dealing with large volumes of extracted water can become a significant factor in the economic viability of GCS projects. We believe that it is premature to draw general conclusions about the economic viability of pressure management via brine extraction, given that treatment options and costs are a field of active research and that most cost factors, as well as synergistic opportunities, are site specific. However, we also believe that it will be useful in many cases to minimize the volume of extracted brine (much below an extraction ratio of one) while still accomplishing specific pressure-reduction goals needed for safe GCS operations.

Therefore, in this study, we introduce the concept of "impact-driven pressure management (IDPM)", with which we mean fluid extraction schemes that are optimized to meet local performance criteria directly related to specific project risks. In other words, instead of assuming that as much brine needs to be extracted as CO_2 is injected, our objective is a targeted brine extraction which limits pressure locally, wherever restriction is necessary to reduce pressurization impacts. For example, a CO_2 storage site might be at risk mostly because of pressure increases near a distant fault that is considered critically stressed and may be reactivated. According to the IDPM concept, an optimal management design would be a near-impact array of fluid extraction wells near the fault. In this case, we would expect that IDPM can lead to a significant reduction in extraction volumes compared to other pressure management schemes, which often assume distributed arrangement of extraction wells (e.g., well arrays placed in a ring pattern around the CO_2 injection wells just outside the projected plume) and which are operating at an extraction ratio of one.

Our current study is a first step in evaluating the effectiveness of IDPM via brine extraction to reduce pressure at local target zones. We illustrate IDPM options and potential benefits in an idealized example case involving a large-scale CO_2 storage operation in a saline formation with a critically stressed fault. Using a newly developed analytical solution for single-phase flow in multilayered aquifer and aquitard systems, we test alternative brine-extraction designs involving active pumping wells and (passive) pressure relief wells (e.g., Bergmo et al., 2011), as well as combinations of both. We define a maximum allowable pressure near the fault zone as the performance criterion for IDPM, and evaluate the selected extraction designs as to their ability to satisfy this criterion. An automated optimization procedure using the inverse modeling framework iTOUGH2 (Finsterle, 2007) is employed to determine the required pumping rate of active extraction wells. Note that the use of an analytical solution is beneficial in computational efficiency, but also requires various simplifying assumptions. In future studies, IDPM will need to be tested for more complex and realistic settings, in which case a multiphase flow simulator is required instead of analytical calculations.

We expect that IDPM will not be beneficial, or even applicable, in all cases where pressure impacts from CO_2 require pressure management solutions. The concept of IDPM makes sense when the impact of pressure buildup needs to be mitigated at local target zones with known locations. The distant fault example studied here is one such example; other examples may include: (1) a distant area with long history of oil and gas production, where leakage along abandoned wells may be a concern, (2) other distant georesource operations, such as geothermal or gas storage fields, where pressure effects may not be tolerable, or (3) a second CO_2 storage project operating in the same formation so that pressure interference between them needs to be avoided. There are other scenarios in which a significant reduction in brine-extraction volumes (below an extraction volume of one) should not be expected from IDPM. For example, abandoned wells with leakage potential may be ubiquitously distributed within much of the pressure-affected area, so that pressure management would have to provide regional, not local, pressure relief. Or CO_2 might be injected into a small compartmentalized formation in which sufficient storage capacity can only be achieved by extraction of large volumes of brine. In addition, project managers might prefer extraction ratios close to one for other reasons (Buscheck et al., 2011b)—for example, to limit the size of the pressure-impacted area to reduce characterization and monitoring cost, to improve public acceptance, or to manipulate the CO_2 plume and improve CO_2 injectivity. It is obvious that decisions about pressure management will need to be made on a case-by-case basis, taking into account reservoir characteristics, pressure-relief needs and objectives, and economic drivers. IDPM, with the objective of minimizing extraction volumes and cost, is one possible approach complementing other approaches that pursue different goals, such as the ACRM concept suggested by Buscheck et al. (2011a,b).

2. Methodology

2.1. Generic example case

To evaluate IDPM options, we conduct calculations of pressure increase and fluid migration using a generic and idealized

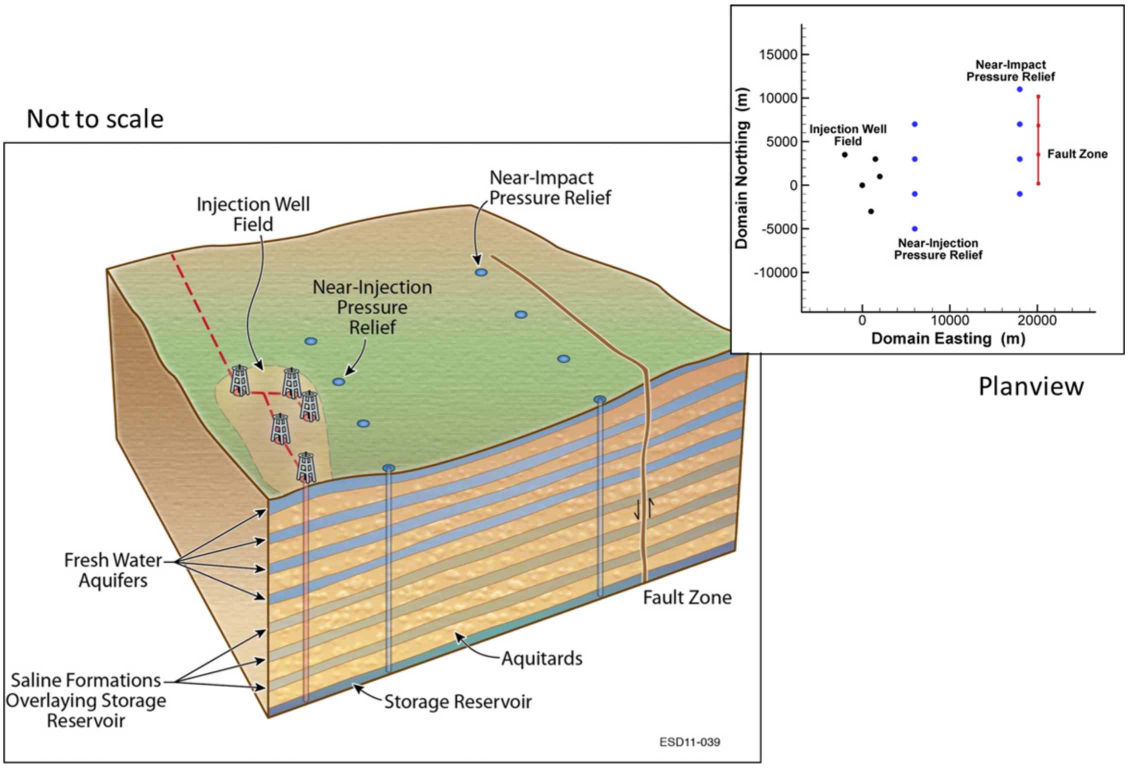

Fig. 1. A generic example for IDPM demonstration. Injection for geological carbon sequestration occurs in five wells on the west side of the domain. A fault zone is located to the east of the proposed injection region.

example as shown in Fig. 1. Some features of this example, in particular those related to potential risks such as the existence of a fault zone, are based on a hypothetical site described in a recent guidance document on carbon sequestration regulation by the United States Environmental Protection Agency (USEPA, 2011). We assume a GCS scenario with injection of about 5 million tons per year of CO_2 over 50 years into a saline formation located at the bottom of a multi-aquifer system. Five injection wells are planned in the center of the domain, each injecting at a constant rate of 1 million tons per year. The total volume of CO_2 injected over 50 years is 250 million tons, which at the assumed pressure and temperature conditions corresponds to a total fluid volume of about 305 million m^3. A vertical fault zone of 10 km length is located to the far east of the injection zone, about 20 km away. We assume that the location of the fault zone is known and that it is close to a critical stress state at which fault slip might be induced. As a performance criterion for pressure management, we postulate that the fault shall not be pressurized above a (arbitrarily chosen) critical value of 40 m head increase to avoid reactivation. (If the fault were vertically conductive, one could also envision a performance criterion that involves a maximum fault leakage rate.) Because the total injection rate is distributed over five wells and the storage formation is assumed to be sufficiently permeable, we expect a moderate pressure increase near the injection zone; i.e., we assume in this study that the local injection pressure remains well below the pressure range that might lead to geomechanical damage in the injection reservoir or in the intact caprock above it. In our example case, the concern about pressurization is rather related to fluid-pressure increase away from the injection wells, at the fault zone.

Similar to a simulation study by Birkholzer et al. (2009), the GCS storage formation is 60 m thick and located at a depth between 1120 m and 1180 m below the ground surface. The storage formation, situated above impermeable bedrock, is bounded at the top by a sealing layer of 100 m thickness, followed by a sequence of 60 m thick aquifers and 100 m thick sealing layers. Altogether, the model domain includes eight aquifers and seven aquitards, with Aquifer 1 the storage formation, Aquitard 1 the primary confining unit above the storage formation, and Aquifer 8 the uppermost aquifer nearest to the ground surface, assumed to be confined in this study. All aquifers and aquitards are assumed to have infinite extent, representing a laterally open hydrogeologic system (Zhou et al., 2008). Low salinity levels representative of fresh water are assumed over the top 540 m of the model domain, followed by increasing salinity levels with depth up to approximately 156,000 mg/L (Birkholzer et al., 2009, Fig. 3). In other words, in this scenario, the top four aquifers, referred to as Aquifers 5 through 8, are considered freshwater resources that would need to be protected. Aquifers 1 through 4, in contrast, are formations with brackish or saline water.

It has been shown that the far-field fluid pressure outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation—without account of local two-phase flow and variable density effects—simply by representing the CO_2 injection as an equivalent-volume injection of a fluid with properties identical to the saline water initially residing in the reservoir (Nicot, 2008; Cihan et al., 2012). Because we focus on the changes in the far-field fluid pressure outside of the expected CO_2 plume domain, we can make the same approximation in our IDPM concept study and use an efficient analytical solution developed for single-phase flow in multilayer aquifer and aquitard systems (Cihan et al., 2011). This solution captures most of the geometrical and flow features relevant for the idealized example shown in Fig. 1; i.e., it can handle aquifer–aquitard systems with any number of layers involving slow brine migration into low-permeability aquitards (also referred to as diffuse leakage) and any number of injection/pumping and leaky wells (see Section 2.2). Diffuse leakage into and through the aquitards was found to be an important process in industrial-scale pressurization studies, because over large areas, even low-permeability caprocks allow for considerable brine leakage out of the formation vertically upward and/or downward (Birkholzer et al., 2009; Cavanagh et al., 2010). Because of the single-phase flow assumption, however, the possibility of CO_2 breakthrough in brine-extraction wells cannot be evaluated with the analytical solution.

The hydraulic properties of the multilayer system are based on previous pressure and brine displacement investigations for industrial-scale storage of CO_2 in a deep sedimentary sandstone aquifer (Birkholzer et al., 2009, 2011). All stratigraphic layers are assumed to be homogeneous; furthermore, the formation properties of all aquifers are the same (permeability of 3×10^{-13} m^2, porosity of 0.2, and pore compressibility of 4.5×10^{-10} Pa^{-1}), and so are the formation properties of all aquitards (permeability of 10^{-18} m^2, porosity of 0.15, and pore compressibility of 9.0×10^{-10} Pa^{-1}). Fluid properties such as density, viscosity, and compressibility vary with depth, on a layer-wise basis, assuming the same vertical variability of initial pressure, temperature, and salinity as in Birkholzer et al. (2009). Thus, the hydraulic conductivity and specific storativity of each aquifer (and aquitard) used in the analytical solution vary accordingly with depth. The hydraulic conductivity of the storage formation is approximately 0.3 m/d, based on a brine density of ρ = 1096 kg/m^3, brine viscosity of μ = 0.92 × 10^{-3} Pa s, and gravity acceleration of g = 9.8 m/s^2. Specific storativity in the storage aquifer is approximately 1.7×10^{-6} 1/m, calculated using $S_s = \phi \rho g(\beta_w + \beta_p)$, where ϕ is porosity, β_w is water compressibility 3.4×10^{-10} Pa^{-1}, and β_p is pore compressibility. The entire domain is initially at a hydrostatic condition. The equivalent brine injection volume tric rate at each of the five wells is 3343 m^3/d (a total of 16,715 m^3/d), which corresponds to a total injection volume of 6.1 million m^3 per year. Assuming a CO_2 density of 820 kg/m^3, this volume is equivalent to an annual CO_2 injection rate of 5 million tons. Injection occurs over the entire thickness of the storage formation. All wells in this study (injection, extraction, and leaky wells) have a diameter of 0.15 m. As to the fault, it is assumed that the faulting process has no effect on aquifer or aquitard properties.

2.2. Analytical solution method and calculation assumptions

The calculations presented in Section 3 are conducted for an idealized example, using an analytical solution for single-phase flow in a system of multiple aquifers and aquitards with multiple injection/pumping wells and multiple leaky wells (Cihan et al., 2011). In this solution, all aquifers and aquitards are horizontal and homogeneous, with uniform thickness and infinite extent. Individual layers, however, may have different thicknesses and properties. The equations of horizontal flow in the aquifers are coupled by the equations of vertical flow in the aquitards and by the flow continuity equations in the leaky wells. The solution methodology, described in detail in Cihan et al. (2011), involves transforming the transient flow equations into the Laplace domain, decoupling the resulting ordinary differential equations (ODEs) coupled by diffuse leakage via Eigenvalue analysis, solving a system of linear algebraic equations for the unknown flow rates through leaky wells, and superposing the solution of pressure buildup/drawdown in aquifers and aquitards resulting from flow in the injection/pumping and leaky wells. The analytical solutions calculate the transient behavior of head (or pressure) buildup in all aquifers and aquitards, the rate of diffuse leakage through aquitards, and the rate of focused leakage through leaky wells.

Leaky wells are handled in the analytical solution as vertical pathways that may connect, via screen intervals, any number of selected aquifers with each other and/or the ground surface. Different hydraulic properties may be assigned to individual well segments. For example, well segments with a very large effective permeability may represent an open wellbore, while a very small or zero effective permeability may represent a well plug. In the context of this study, we use the leaky well option to simulate pressure-management options involving passive-pressure-relief wells. Passive relief relies on the pressure increase in the storage formation providing the driving force for brine flow through wells, either bringing brine up to the surface or transferring it into suitable over- or underlying formations. (Here, "suitable formations" mean that these are sufficiently permeable and have high salinity, so that they are not considered protectable groundwater resources.) Based on a Darcy type flow approximation, pressure relief wells are treated as an equivalent porous medium with a porosity of one and a very high effective permeability (i.e., 10^{-5} m^2 or 10^7 m/d), corresponding to a case with very little resistance to flow.

3. Calculation cases and results

3.1. Pressure management scenarios

We operate under the premise that the cost of extracting, transporting, treating, and/or disposing of brine for the purpose of pressure management may jeopardize the economic viability of a GCS project, and we propose the concept of IDPM with the objective of minimizing brine extraction via optimization of pressure-management schemes. As depicted in Fig. 1, we compare two different options for the placement of brine-extraction wells, each featuring four wells arranged in a line pattern along the north-south direction, to provide a low-pressure curtain between the zones of CO_2 injection and the region of potential impact. (Another option not studied here would be to place one horizontal well instead of four vertical wells.) One placement option is near the zone of CO_2 injection (near-injection array), with the extraction wells placed at a minimum distance of 4.5 km away from CO_2 injectors. Another option is near the distant fault (near-impact array), in which case we assume a 2 km distance between the extraction wells and the fault line. For each well placement option, we simulate brine extraction via active pumping or via pressure-driven passive relief, and we also distinguish between cases where the extracted fluids are brought to the surface or are transferred into suitable saline aquifers above the storage formation. The possibility of CO_2 being pulled into brine-extraction wells is not addressed in this study—something to keep in mind when comparing the two well-placement options. Based on work by Buscheck et al. (2011c), we may expect that the near-injection scheme is unlikely to function over the full 50-year injection period without CO_2 arrival in extraction wells.

As mentioned above, the generic example assumes that the performance criterion for IDPM is a maximum head change of 40 m in the fault zone located about 20 km west of the CO_2 injection field. Of course, the basic concept of IDPM illustrated by this example could be applied to other potential pressurization impacts that need to be avoided or minimized. For example, instead of (or in addition to) reactivation of a critically stressed fault, pressure buildup could be a concern because of a second CO_2 storage project in the same formation. Or pressure changes might result in brine leakage in a depleted oil and gas field (located at some distance from the CO_2 injection wells), in which small subset wells may be improperly abandoned and potentially conductive. Areas with a long history of oil and gas production are often perforated by hundreds, if not thousands of wells, many of which are decades old with uncertain properties (e.g., Gasda et al., 2004). The performance criterion for pressure management in this case may be a maximum well leakage rate, provided that the permeability distribution of leaky wells can be estimated.

3.2. Results and discussion

3.2.1. Pressure and brine migration predictions without IDPM

Injection of CO_2 at a rate of 5 million tons per year (equivalent brine volume of 6.1 million m^3 per year) for a period of 50 years

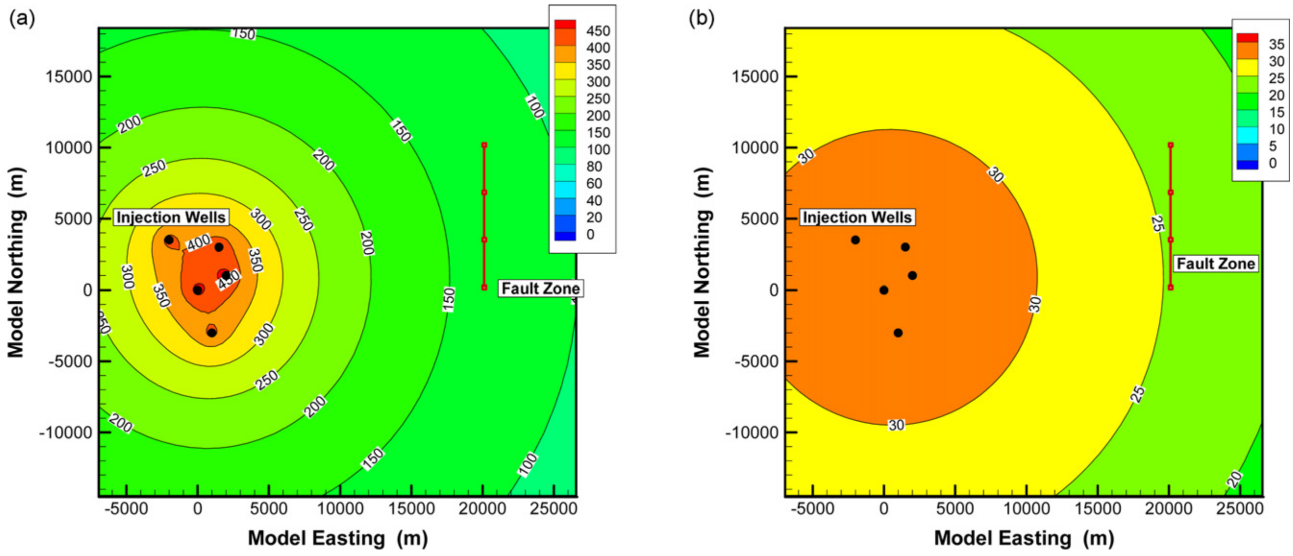

Fig. 2. Contour plot of hydraulic head changes (in m) at 50 years of CO_2 injection: (a) in the storage formation, and (b) in Aquifer 2 (first aquifer above storage formation).

generates strong and spatially extensive pressure perturbations in the storage formation. Within the storage formation (Fig. 2a), the hydraulic heads in the region near the injection wells increase by up to 500 m (about 50 bar) at the end of the injection period, while the fault zone experiences head changes up to 130 m (about 13 bar). Moderate increases in hydraulic head can also be seen in overlying aquifers (e.g., Fig. 2b), a result of vertical brine migration from the storage formation through the confining aquitards. Fig. 3a compares the time evolution of diffuse leakage through aquitards with the volumetric injection rate, suggesting substantial volumes of brine extracted from the storage formation through natural brine-migration processes. As noted in earlier studies (e.g., Birkholzer et al., 2009), while diffuse leakage has a positive attenuation effect on the pressure conditions within the storage formation, it is generally not a concern for shallower aquifers, because of the very small migration velocities associated with the vertical transport. Aquitard permeability has a considerable impact on the pressure conditions in the storage formation. As evident from Fig. 3b, a one-order-of-magnitude higher aquitard permeability (10^{-17} m^2 instead of 10^{-18} m^2) brings the hydraulic head increase in the fault location down to about 65 m; in contrast, a head increase of more than 200 m is observed when aquitard permeability is negligible (10^{-19} m^2). Hence, when estimating large-scale pressure perturbations (and possibly making important decisions about pressure-management options), we need to ensure that accurate permeability estimates are available, not only for the storage formation but also for the confining layers.

3.2.2. Pressure management via active brine extraction

The first IDPM scenario involves active extraction of brine from the storage formation. Pumping rates are adjusted over time in a stepwise manner such that the head increase along the fault zone does not exceed 40 m. (It is first assumed that the extracted brines can be brought to the surface and either be disposed of or treated for beneficial use.) Optimal pumping rates were determined iteratively by forward simulations using the analytical solution described in

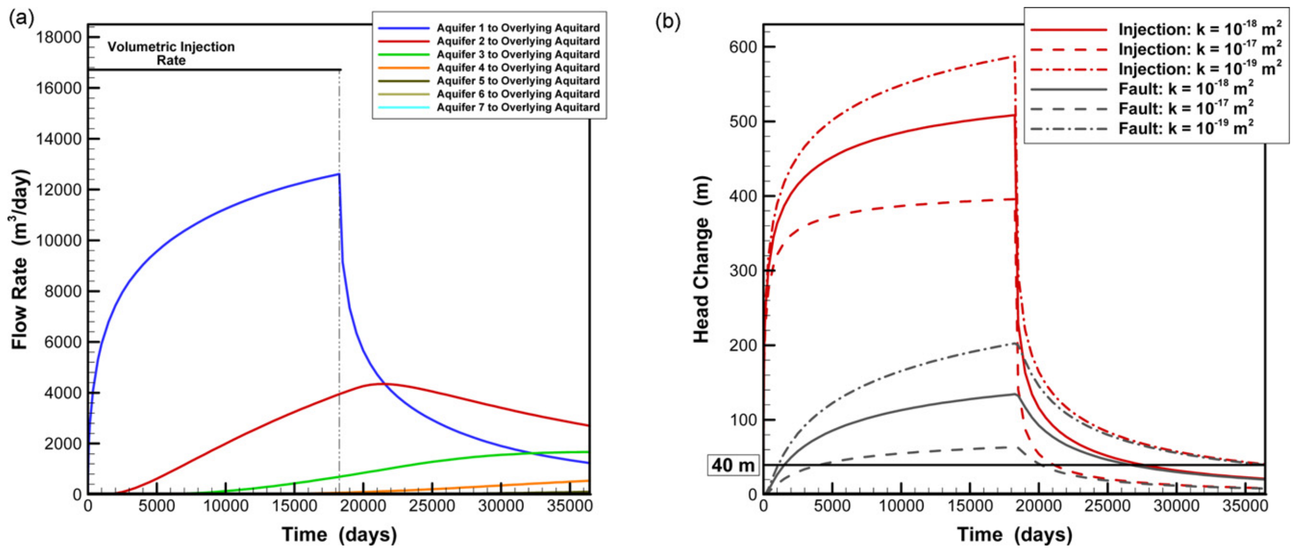

Fig. 3. (a) Diffuse leakage flow rates (in m^3/d) from aquifers into overlying aquitards, for an aquitard permeability of 10^{-18} m^2. Flow rates are integrated over total domain size. Aquifer 1 is the storage formation. (b) Evolution of hydraulic head changes (in m) at two locations in the storage formation, one in the fault zone at x = 20,000 m and y = 0 m, and the second near the injection wells at x = 50 m and y = 0 m, for three different aquitard permeabilities. The 40-m performance criterion for the fault zone is also shown.

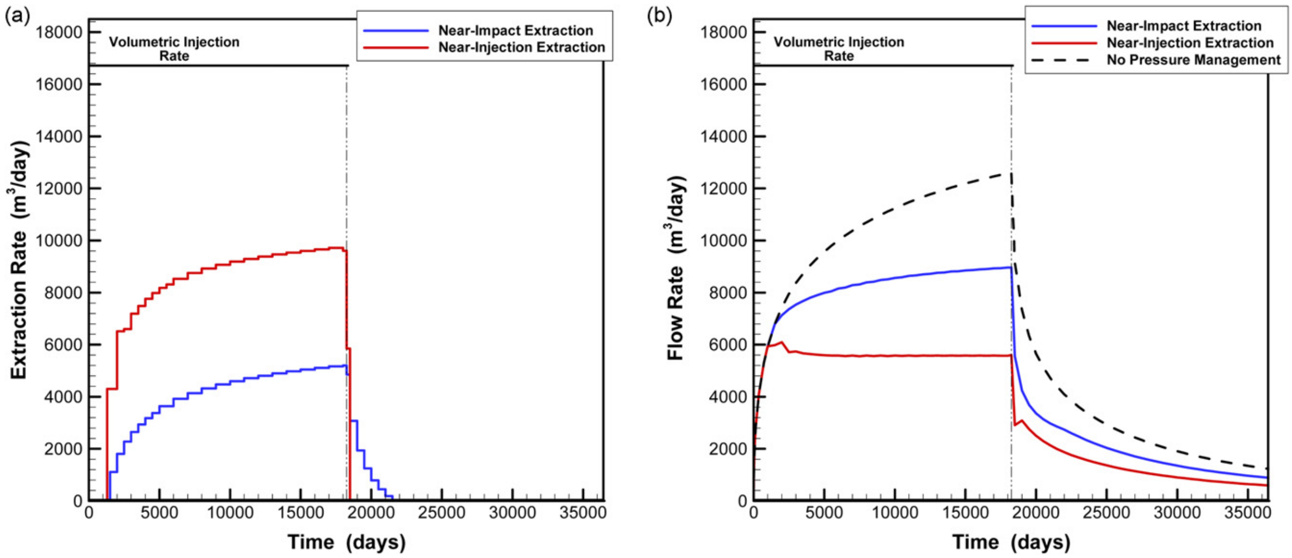

Fig. 4. (a) Optimized extraction rates for near-impact and near-injection options. (b) Diffuse leakage flow rates (in m^3/d) from storage formation into overlying aquitard, integrated over total domain size.

Section 2.2 and by inverse modeling using the iTOUGH2 framework (Finsterle, 2007). We utilize a recent iTOUGH2 enhancement that now makes its optimization capabilities available to any external forward simulator via the PEST protocol interface (Finsterle, 2010). The analytical solution is particularly useful in this automated inversion effort, because it produces calculation results much faster than a complex multiphase numerical process model.

Optimization of pumping rates was conducted for the two alternative well-placement arrays introduced earlier, i.e., the near-injection and near-impact arrays. In both cases, we assume that all four extraction wells have identical pumping rates. Fig. 4a shows the total extraction rate from all four wells as a function of time. Both placement options allow for a significant reduction in brine-extraction rates compared to pressure-management schemes operating at an extraction ratio of one. The near-impact placement array with wells aligned near the fault is advantageous in terms of the total brine volumes that need to be extracted to meet the 40 m head buildup criterion: The total near-impact extraction volume is 70.9 million m^3 compared to the total near-injection volume of 148.0 million m^3. These values correspond to 23.2% and 48.5%, respectively, of the total injected CO_2 volume of 305 million m^3.

By targeting extractions to a local performance criterion, IDPM clearly has the potential of reducing the total extraction volume for pressure management. Notice in Fig. 4a that pumping does not start immediately when CO_2 injection begins, because the pressure perturbation needs a few years to propagate to the fault location and buildup to the allowed 40 m head change. A similar delay due to system inertia is seen after injection stops, when pumping needs to continue for a while to avoid a pressure spike.

Active extraction of brine leads to a considerable reduction in the rates of diffuse leakage from the storage formation into the overlying layers (Fig. 4b). As more brine is extracted (resulting in less head buildup in the storage formation), the driving force for vertical inter-layer communication decreases, and diffuse brine migration through the aquitards becomes less effective. In other words, the pressure-mitigation effect generated by diffuse leakage in a case without pressure management needs to

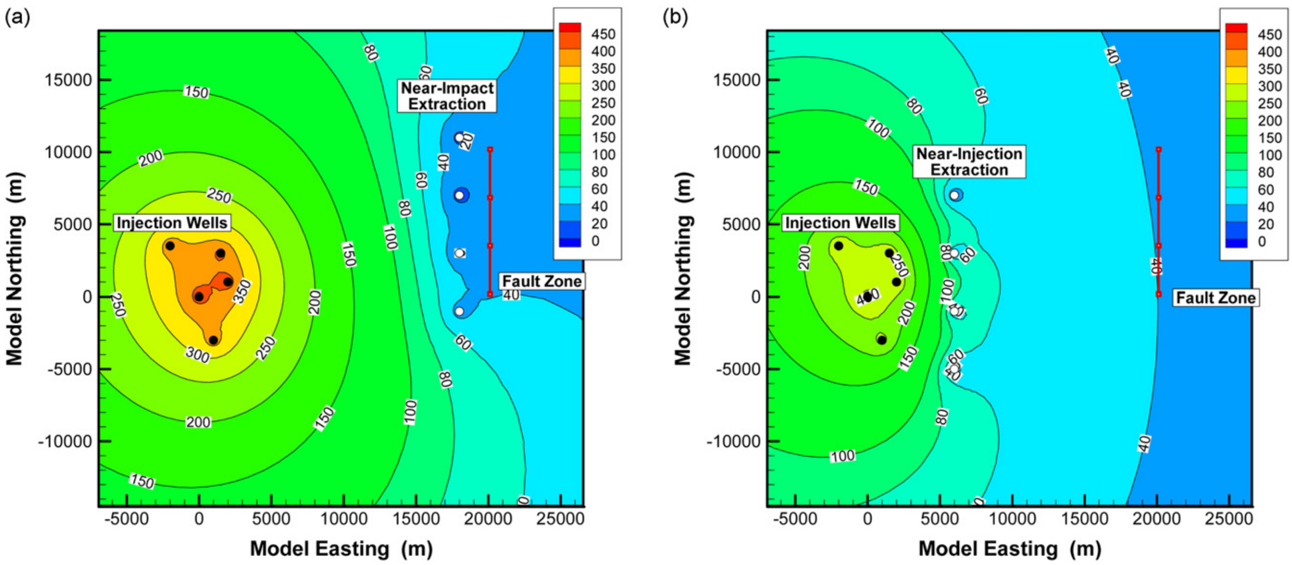

Fig. 5. Contour plots of hydraulic head changes (in m) in the storage formation at 50 years of CO_2 injection: (a) for near-impact extraction, and (b) for near-injection extraction.

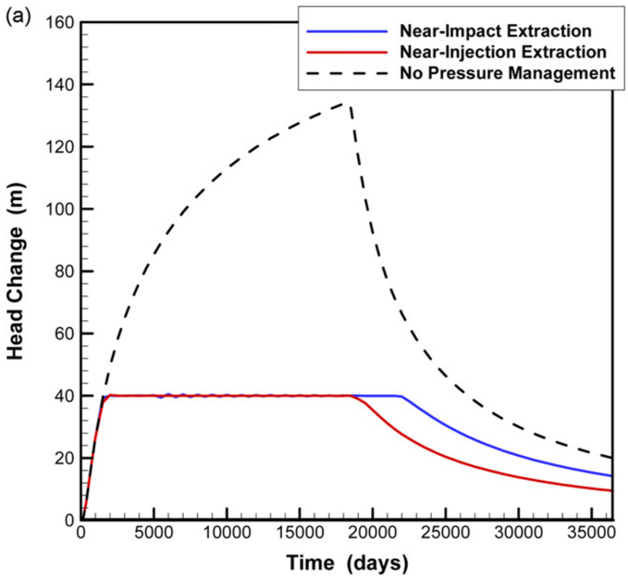

Fig. 6. Evolution of hydraulic head changes (in m): (a) in the fault zone at $x = 20,000$ m and $y = 0$ m, and (b) near the injection wells at $x = 50$ m and $y = 0$ m.

be partially compensated for when brines are actively extracted from the formation. Diffuse leakage, however, remains important in all three cases shown in Fig. 4b, with the overall rates of diffuse leakage slightly higher (near-impact scheme) or slightly lower (near-injection scheme) than the active pumping rates.

Figs. 5 and 6 illustrate the head changes in the storage formation for the two brine extraction schemes. The target criterion of 40 m head change along the fault zone is achieved in both cases, a significant reduction compared to the strong pressurization without any pressure management (Fig. 6a). However, the spatial patterns of hydraulic head changes are quite different between the near-impact and the near-injection arrays (Fig. 5). The effect of brine extraction is localized around the fault zone in the near-impact scenario, whereas the injection region is only minimally affected. The near-injection extraction, in contrast, shows a more regional effect of pressure management, reducing the head changes in a much larger area. Of course, this added benefit of more regional pressure reduction comes at the cost of substantially higher brine extraction rates (and increases the possibility of CO_2 breakthrough into the extraction wells).

A question arises as to what extent targeted brine extraction is affected by the formation properties of the storage reservoir. To explore related sensitivities, we conducted a similar optimization of pumping rates with two additional aquifer permeability cases, one in which aquifer permeability is reduced by a factor of three (low-permeability case), the other in which aquifer permeability is increased by a factor of three (high-permeability case). As depicted in Fig. 7a, without managing formation pressure, the head changes in the fault zone reach a maximum of 218 m in the low-permeability case and a maximum of only 68 m in the high-permeability case. It is obvious that the nature of the pressure-management scenario is strongly affected by the formation properties. A case with even higher aquifer permeability might result in head increases at the fault that are less than the performance criterion of 40 m,

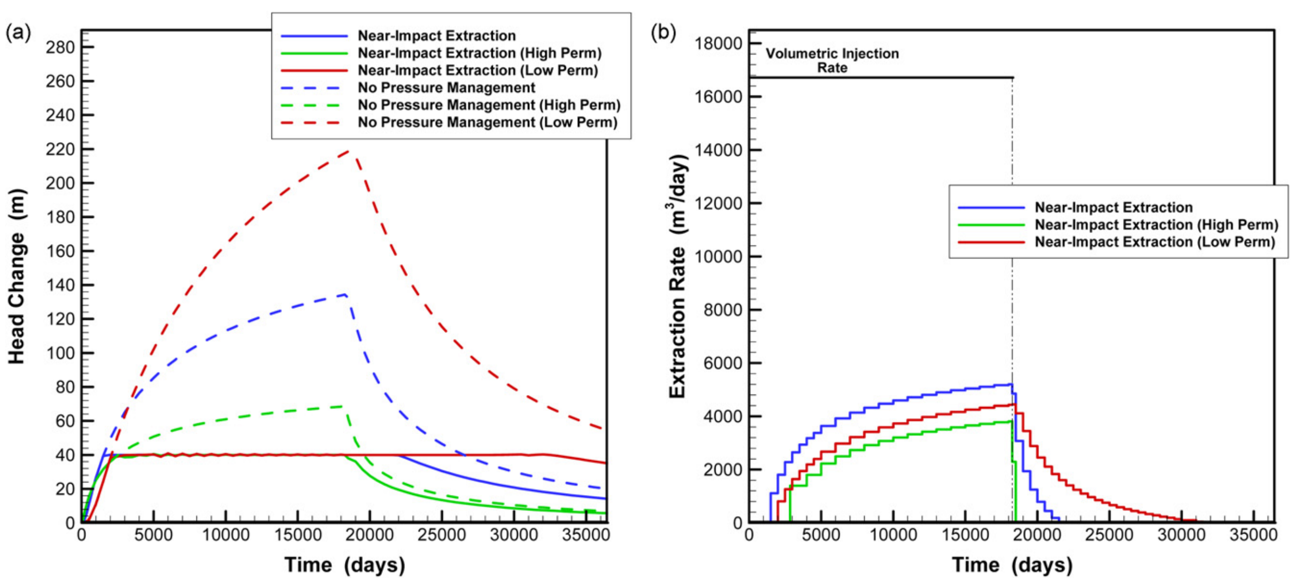

Fig. 7. Comparison of sensitivity cases with different storage formation permeabilities. (a) Evolution of hydraulic head changes (in m) in the fault zone at $x = 20,000$ m and $y = 0$ m. (b) Optimized extraction rates. Extraction is conducted in the near-impact array.

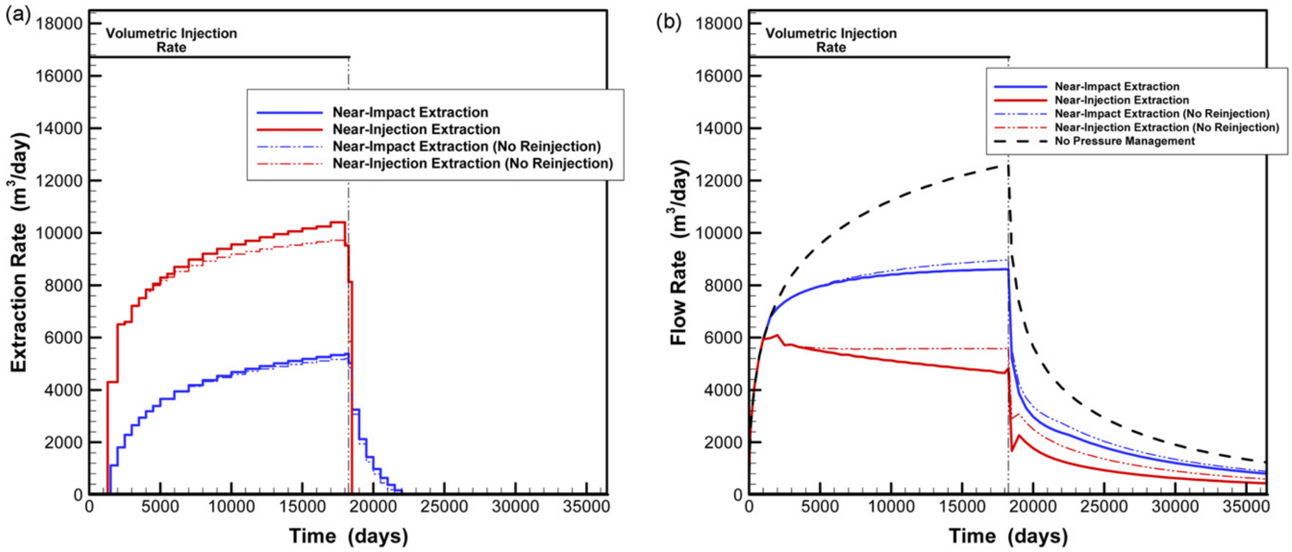

Fig. 8. (a) Optimized extraction rates for near-impact and near-injection schemes, with and without reinjection into three overlying saline aquifers. (b) Diffuse leakage flow rates (in m^3/d) from storage formation into the overlying aquitard, integrated over total domain size.

meaning pressure management would not be necessary. In contrast, a case with even lower aquifer permeability could generate very high formation pressure near the injection wells, which might not be tolerable and would require a larger number of injection wells. The factor-of-three decrease/increase selected for this sensitivity study was based on the premise that the low-permeability case should not create unreasonably high pressure changes, and that the high-permeability case should still exhibit head increases above the performance criterion.

Fig. 7b shows the active extraction rates for the base-case scenario and the two sensitivity cases, with pumping occurring in the near-impact array. (Similar sensitivity results were observed for the near-injection placement). The target performance criterion can be achieved in all cases, and the extraction rates are not all that different from the base case. This is because aquifer permeability not only strongly affects head increase in the fault, it also changes the extraction rate required to reduce a given head increase. For example, the low-permeability case results in much higher pressure along the fault, meaning that a more significant pressure reduction needs to be achieved to meet the performance criterion. However, because of the lower permeability, the pumping rate required for this pressure reduction is actually less than in the base case (but pumping need to be maintained over a longer time period after injection ceases). As a result, the total pumping volume required in the low-permeability case is only slightly higher than in the base case, at 28.2% of the injection volume compared to 23.4%. A relative total pumping volume of 18.6% is required in the high-permeability case.

The cost of brine extraction can be reduced if the brines pumped from the storage formation are not brought to the surface, but rather disposed of in suitable saline formations, using the same wells for extraction and reinjection. Going back to the base-case formation properties, we have simulated reinjection options for both well-placement scenarios, again determining optimal brine-extraction rates using iTOUGH2, while this time transferring the extracted fluid volumes into the three saline reservoirs overlying the storage formation. At each well and each calculation time step,

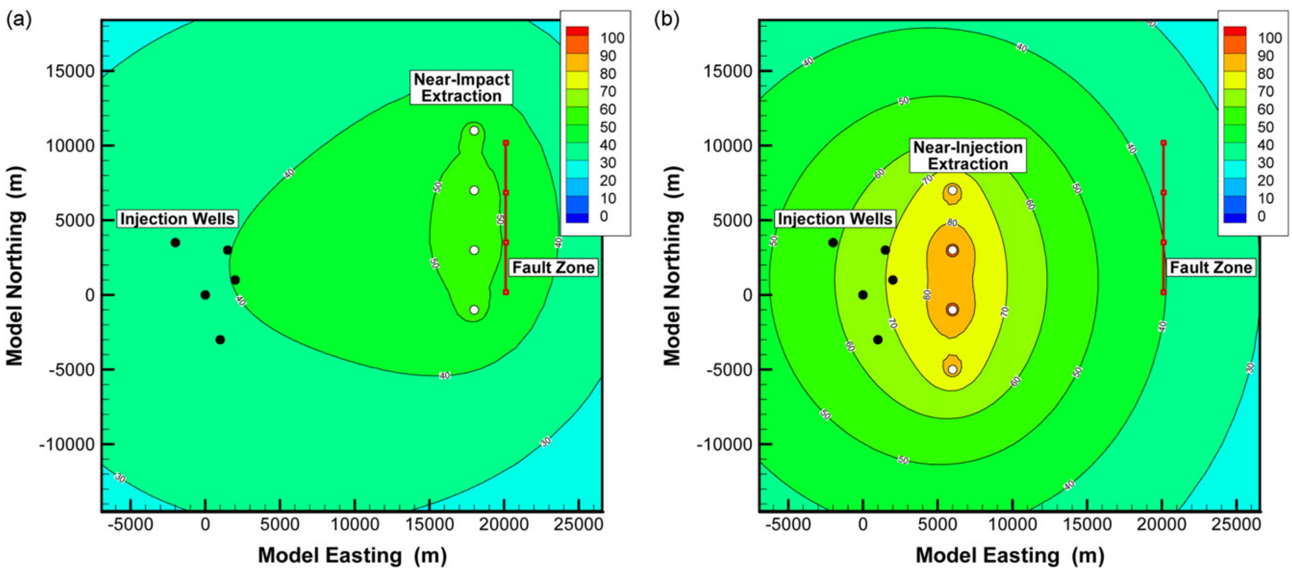

Fig. 9. Contour plots of hydraulic head changes (in m) in Aquifer 2 (the first aquifer above the storage formation) at 50 years of CO_2 injection: (a) for near-impact extraction with reinjection into three overlying aquifers, and (b) for near-injection extraction with reinjection into three overlying aquifers.

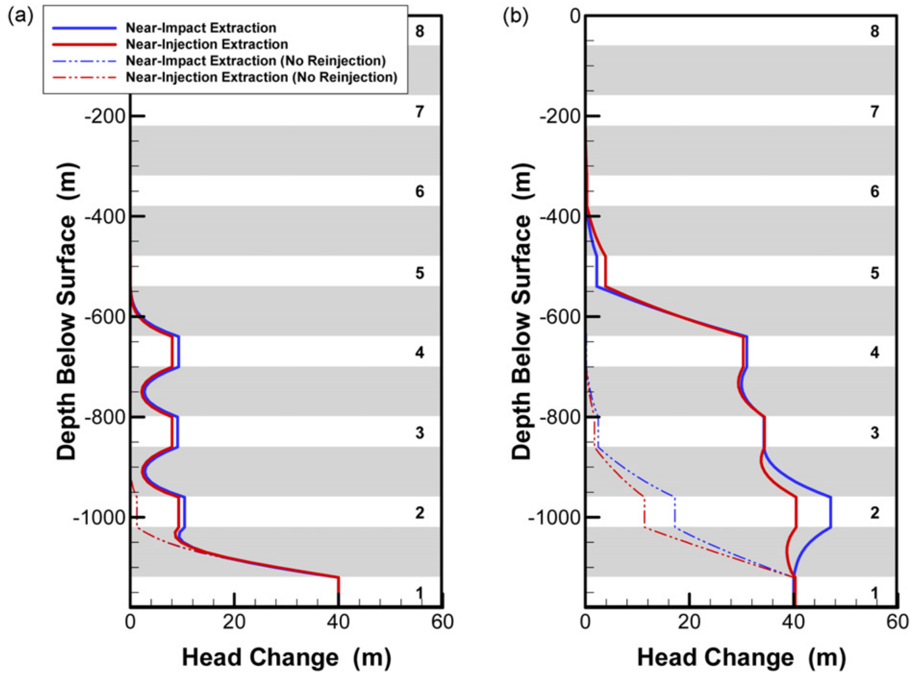

Fig. 10. Vertical profiles of hydraulic head changes (in m) in the fault zone at $x = 20{,}000$ m and $y = 0$ m at (a) 10 years and (b) 50 years of CO_2 injection. Numbers indicate aquifers of the multi-layer domain; shaded areas represent aquitards.

one third of the brine taken out of the storage formation is immediately injected into Aquifers 2, 3, and 4, respectively. As evident from Fig. 8a, the brine extraction rates necessary to avoid overpressurization in the fault zone are similar in trend but slightly higher for the case with brine reinjection compared to surface disposal. This has to do with the changes to the magnitude of diffuse brine leakage from the storage formation into the overlying aquitards and aquifers (Fig. 8b). Brine reinjection causes head increases in Aquifers 2, 3, and 4 (see example contours in Fig. 9), which in turn reduces the driving force for diffuse brine leakage through Aquitards 1, 2, and 3. This effect is less strong in the near-impact scenario because the overall extraction and reinjection rates are smaller. In total, for the cases with brine reinjection into Aquifers 2, 3, and 4, the near-impact extraction volume is 71.4 million m^3 compared to 153.8 million m^3 in the near-injection scenario. These values correspond to 23.4% and 50.4%, respectively, of the total injected CO_2 volume of 305 million m^3.

While it may be economically beneficial, reinjection of brine may cause its own set of problems in the multilayer domain, as shown in the vertical head profiles in Fig. 10. At 10 years of CO_2 injection, the head increases in the fault zone are modest, with values less than 10 m in Aquifers 2, 3, and 4. At 50 years, however, reinjection into these aquifers causes the hydraulic heads near the fault zone to increase to values similar to the storage formation, which raises additional concerns about fault reactivation. In the near-impact extraction scenario, the hydraulic head in Aquifer 2

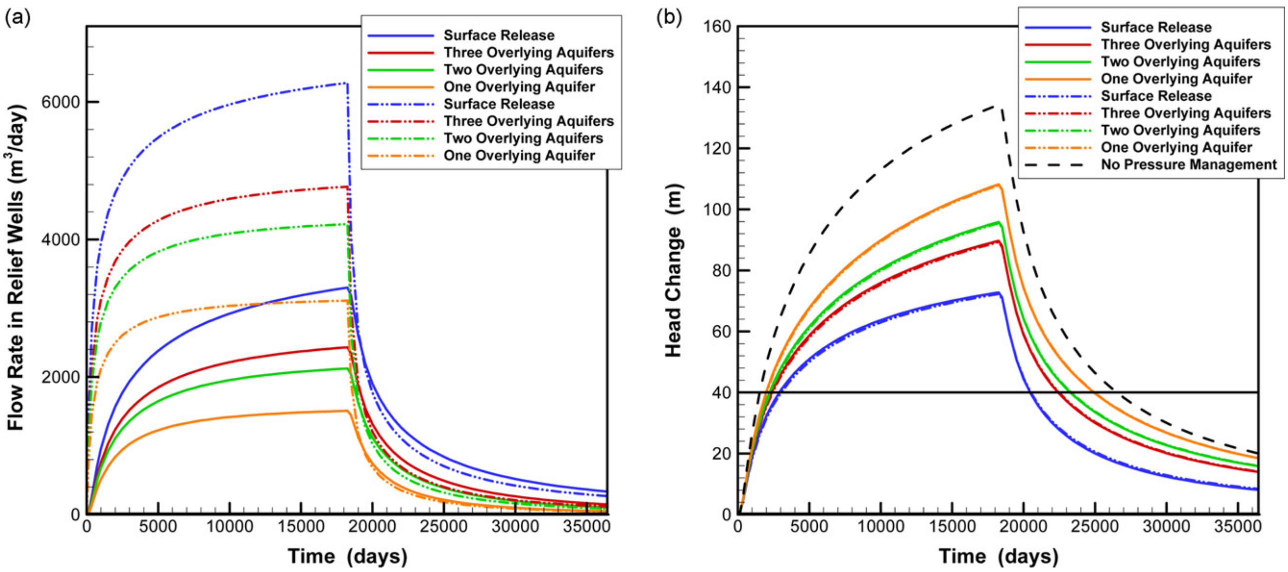

Fig. 11. (a) Flow rates out of storage formation through passive pressure relief wells, for near-impact (solid lines) and near-injection (dashed-dotted lines) schemes. (b) Evolution of hydraulic head changes (in m) in the fault zone at $x = 20{,}000$ m and $y = 0$ m, for near-impact (solid lines) and near-injection (dashed-dotted lines) schemes. The 40-m performance criterion for the fault zone is also shown.

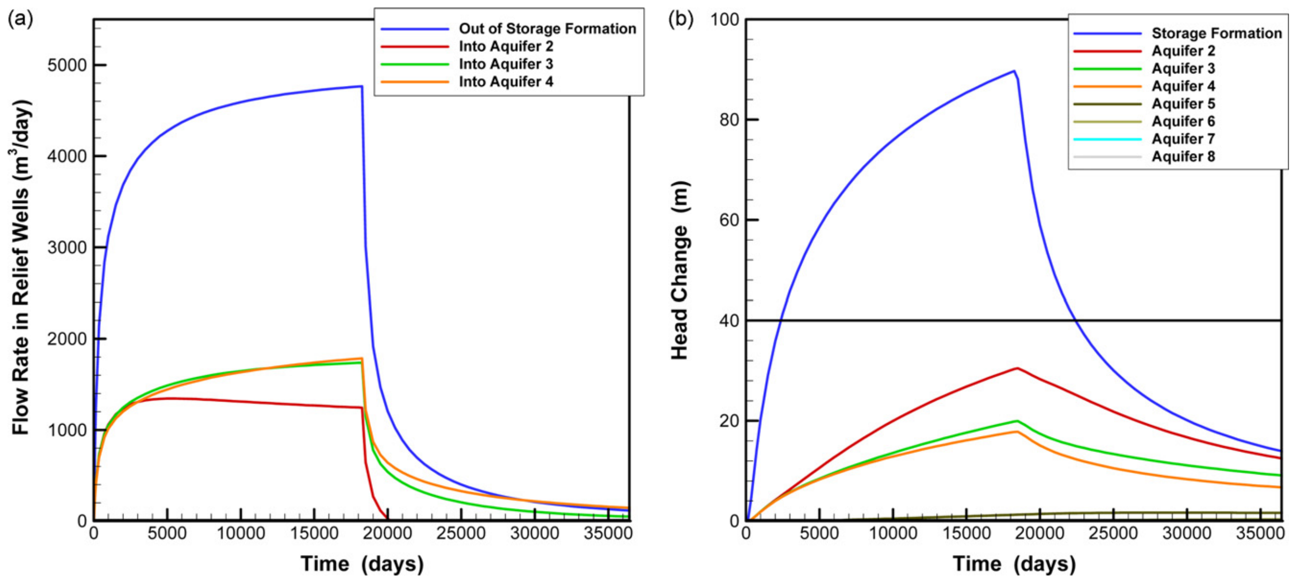

Fig. 12. (a) Flow rates through passive pressure relief wells. (b) Evolution of hydraulic head changes (in m) in the fault zone at $x = 20{,}000$ m and $y = 0$ m. Both graphs are for near-injection well arrays.

actually increases above the 40 m performance criterion. (Our optimization algorithm probes maximum head changes in the storage formation, but not in other stratigraphic layers.) Some fraction of the extracted brine would have to be brought to the surface and possibly injected somewhere else rather than transferred into Aquifer 2. It should also be mentioned that reinjection causes minor head changes in the deepest freshwater aquifer (Aquifer 5), due to diffuse brine flow from Aquifer 4. If reinjection into Aquifers 2, 3, and 4 is pursued as a pressure management option, the potential for environmental impact on Aquifer 5—e.g., from intrusion of high-salinity water—would have to be determined.

3.2.3. *Pressure management via passive-pressure-relief wells*

Instead of active pumping, water-extraction wells can also be operated as passive producers (Bergmo et al., 2011) to reduce operational expenses. Flow in passive wells is caused by the injection-induced increase in formation pressure and not by active pumping. Additional simulations are conducted to determine the feasibility of passive pressure relief for IDPM, again looking at the two alternative well-placement scenarios introduced earlier, i.e., the near-injection and the near-impact arrays. In each scenario, we assume that all four passive-pressure-relief wells have an effective well permeability of 10^{-5} m^2 or 10^7 m/d representative of open wellbore flow. Four different brine disposal options are considered. The first option assumes that the pressure relief wells connect the storage formation with the ground surface. To simulate this case, a zero change in hydraulic head is imposed as a boundary condition at the top of the wells. The other three options assume that the pressure-relief wells connect the storage formation with, respectively, the first one, two, or three overlying saline aquifers; further upward flow is blocked by a well plug. Extracted brine moves up through the wells and discharges into these other aquifers of the multilayer system. As a result, the receiving aquifers experience head increases, and the driving force for passive pressure relief

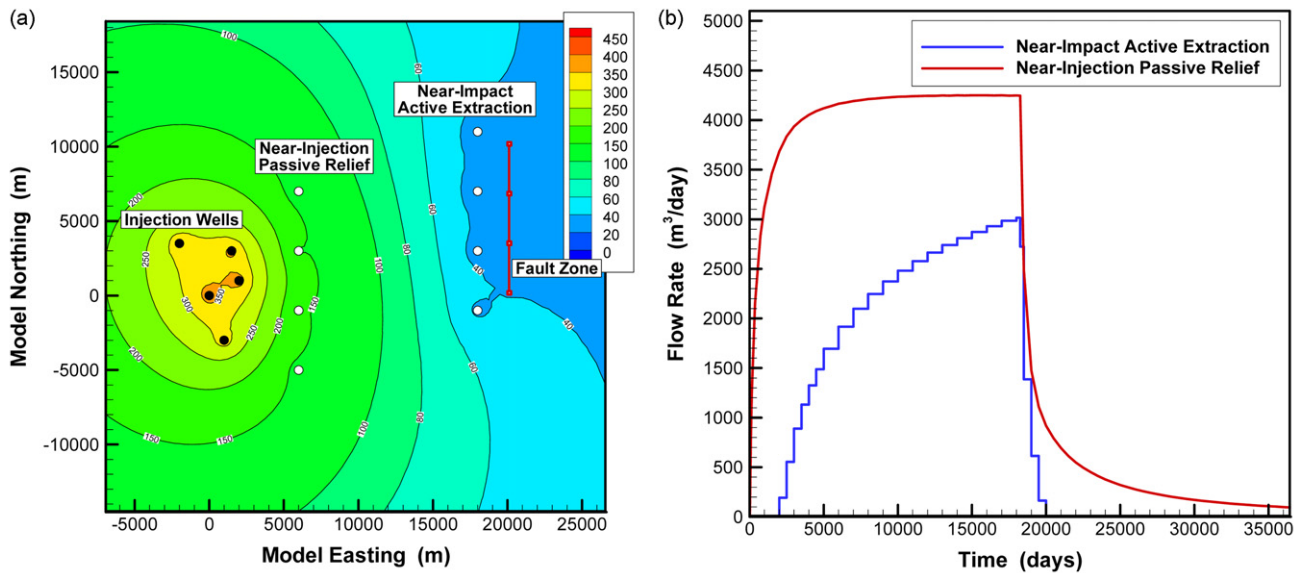

Fig. 13. Combined near-injection pressure relief and near-impact extraction. (a) Contour plots of hydraulic head changes (in m) in the storage formation at 50 years of CO_2 injection, and (b) flow rates extracted from formation through passive pressure relief wells and active extraction wells.

depends not only on the pressure conditions in the storage formation, but also on those in the receiving aquifers.

Fig. 11a shows the total flow rate out of the storage formation from the four passive wells as a function of time, for both well-placement scenarios and all four brine-disposal options. The near-injection placement is about twice as productive as near-impact placement, since the head buildup in the storage formation decreases with distance from the CO_2 injection wells. Note that the flow rates, in both scenarios, are generally lower than the optimized rates for active extraction (compare with Fig. 4a). Comparing the four brine-disposal options, passive relief from the storage formation is most effective in terms of brine-extraction rates when brine is brought all the way to the ground surface, followed by discharge into, respectively, three, two, and one overlying saline aquifers.

While significant brine volumes can be removed with passive-pressure-relief wells, none of the eight IDPM simulation cases achieves the target criterion of keeping the head buildup in the fault zone at 40 m or below (Fig. 11b). While passive pressure relief may save costs, this IDPM method requires that the head increase in the storage formation is high enough to ensure a sufficient driving force for flow up the wells. As can be seen in this example, the need for maintaining a driving force for flow conflicts with the target criterion for pressure management; thus, IDPM success with passive relief wells alone cannot always be guaranteed.

As opposed to active extraction, in terms of pressure reduction, there is no benefit from passive-well placement near the fault zone; both placement scenarios with passive relief wells arrive at nearly identical head increases in the fault zone. Thus, unless the brine is brought to the surface and treatment/transportation cost becomes an issue, placement of wells near the CO_2 injection area (but far enough away to avoid CO_2 production) would be the preferred option for passive relief, because larger volumes can be extracted and pressure reduction is achieved in the near *and* far parts of the aquifer.

Fig. 12 allows a closer look at one of the passive-pressure-relief cases, with near-injection well placement and transfer of the extracted brine into the three overlying saline aquifers. At each time step, the brine extraction rate out of the storage formation equals the sum of the brine discharge rates into Aquifers 2, 3, and 4 (Fig. 12a). The discharge rate into Aquifer 2 is initially similar to that of Aquifers 3 and 4, but starts deviating after about 10 years of CO_2 injection. This is consistent with a trend that can be seen in Fig. 12b starting at about the same time, with the hydraulic head in Aquifer 2 becoming substantially higher than in Aquifers 3 and 4. This additional head increase, which reduces the driving force for passive well flow into Aquifer 2, is caused by the simultaneously occurring recharge via diffuse transfer of brine from the storage formation through Aquitard 1.

The question arises whether it makes sense technically and economically to combine passive pressure relief with active extraction, so that the target criterion for pressure management can be achieved. We simulate an additional scenario in which four near-injection wells are passively connected with Aquifers 2, 3, and 4, while the four near-impact wells are actively pumping at a rate determined by the 40 m head buildup limit in the fault zone. Compared to the active extraction scenarios analyzed earlier (Section 3.2.2), the additional cost for four wells would need to be balanced against the savings generated from pumping, transporting, and treating less saline water. Fig. 13a shows contours of head buildup for this scenario, suggesting that the 40 m target for the fault zone is achieved by the combined scheme. Fig. 13b compares the total flow rates of brine removal from the storage formation via near-injection passive relief and near-impact active extraction. While the majority of brine leaves the storage formation by passive well flow, active extraction is necessary to keep the fault pressure below reactivation pressure. The total volume of active extraction is 36.3 million m^3, which corresponds to 11.9% of the total injected CO_2 volume over the 50-year injection period. In comparison, the active extraction volumes without passive relief calculated above (Section 3.2.2) are 70.9 million m^3 (near-impact scenario) and 148.0 million m^3 (near-injection scenario).

4. Summary and conclusion

Pressure management via extraction of native saline water has been suggested recently in conjunction with large-scale CO_2 sequestration, to reduce failure risk and increase storage capacity in storage formations where pressurization might otherwise be a concern. While there are synergistic advantages and economic benefits resulting from pressure control and brine reuse, the extraction and management of substantial volumes of saline water involves substantial operational costs. Depending on the site-specific conditions, the economic viability of CO_2 sequestration projects may require minimizing the volumes of brine to be extracted and brought to the surface. We introduce in this study the concept of impact-driven pressure management (IDPM), with which we mean optimization of fluid extraction schemes to minimize fluid volumes while meeting defined local performance criteria (i.e., schemes that limit pressure increases primarily where environmental impact is a concern). The effectiveness of IDPM is illustrated in a generic concept study that involves a highly idealized representation of a large-scale CO_2 storage operation in a saline formation with a critically stressed fault. Using a newly developed analytical solution for single-phase flow in multilayer aquifer and aquitard systems, we tested different brine-extraction designs involving active pumping wells and (passive) pressure relief wells in combination with two alternative well-placement options, one with four extraction wells near the zone of CO_2 injection (near-injection array), the other with four extraction wells near the fault (near-impact array). We postulated as a performance criterion for pressure management that the fault zone shall not be pressurized above a critical value of 40 m head increase to avoid reactivation; the selected extraction designs are evaluated as to their ability to satisfy this criterion.

Our hypothetical modeling analysis suggests that IDPM can lead to a considerable reduction in brine-extraction volumes compared to pressure-management schemes that often assume volume-equivalent extractions (i.e., extracted brine volume is equal to injected CO_2 volume). As shown in Section 3.2.2 for active pumping scenarios, the total brine volumes to be extracted from the storage formation to meet the performance criterion are 70.9 million m^3 for the near-impact array and 148.0 million m^3 for the near-injection array, compared to a total CO_2 injection volume of 305 million m^3. These values correspond to extraction volumes of 23.2% and 48.5% of the total injected CO_2 volume, respectively. If one is primarily interested in locally reducing the fault-zone pressures, placement of extraction wells near the area of impact is beneficial, not just in terms of total extraction volume but also because there is much less concern about pulling the CO_2 plume into the extraction wells. Placement of wells near the CO_2 injectors allows for a more regional reduction in formation pressure—at the cost, however, of substantially higher brine-extraction rates.

We also evaluated scenarios in which water extraction wells operate as passive producers; i.e., flow in these wells is caused by the injection-induced increase in formation pressure and not by active pumping. While significant brine volumes can be removed by passive-pressure-relief wells, the target criterion of keeping head buildup in the fault zone at or below 40 m was not met. There is a limit as to how much formation pressure reduction can be achieved by this IDPM method, because the head increase in the storage formation needs to remain high enough to ensure a sufficient head gradient forcing flow through the wells. As a remedy, one may combine passive pressure relief with active extraction. We simulated a scenario in which four passive relief wells near the CO_2 injection region were supplemented by extraction from four active producers located near the fault zone. In this case, the total brine volume extracted by the active producers could be reduced to only 11.9% of the total injected CO_2 volume over the 50-year injection period, while still meeting the 40 m performance criterion.

To save pumping, transportation, and/or treatment expenses, the brines extracted from the storage formation may be disposed of in other suitable saline formations. In an optimal scenario, the same wells could be used for extraction from one formation and immediate transfer into other aquifers, above or below, without bringing the extracted brines to the surface. We evaluated such subsurface disposal options, assuming that the three saline aquifers overlying the storage formation are suitable receivers for extracted brine. In the active extraction cases, immediate reinjection into stacked aquifers is generally a feasible option; however, the pressure buildup in the receiving formations may result in its own set of problems. For example, brine extraction and reinjection in the near-impact well array produced a head buildup in one overlying aquifer that was slightly higher than the performance target of 40 m in the fault zone. In the passive-pressure-relief cases, the brine flow rates that can be extracted from the storage formation are lower if brines are transferred into overlying aquifers rather than brought to the surface. This is because the receiving aquifers experience head increases, which in turn reduce the driving force for passive pressure relief.

Our current study, which considers a hypothetical and highly idealized setting, is only a first step in evaluating the concept of IDPM. Future work needs to test the effectiveness of IDPM for increasingly complex and realistic applications, which would eventually include comparison with observations from existing or emerging CO_2 storage site. Several of the simplifications related to the analytical solution for single-phase flow will need to be relaxed to allow for more complexity and realism, which will require use of a multiphase process model instead of an analytical calculation in the iTOUGH2 optimization runs. Some questions to be addressed are, for example, whether formation heterogeneity will reduce effectiveness of IDPM, whether extraction schemes may result in CO_2 breakthrough at wells, or whether IDPM can be beneficial if CO_2 storage occurs in small compartmentalized formations. In addition, IDPM needs to be evaluated in situations that involve multiple and possibly distributed performance targets, which will challenge the objective of achieving a considerable reduction in brine extraction volumes. We plan to expand the current iTOUGH2 inversion framework to handle multiple performance targets, while simultaneously optimizing the number of extraction wells, well placement, and extraction rates.

Acknowledgments

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